IPPs in APEC ECONOMIES: ISSUES AND TRENDS*

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Abstract

IPPs have changed the energy sector landscape of APEC economies. Ultimately, IPP development can be traced to the ongoing privatization and restructuring in the electricity sectors of APEC economies. However, other forces have driven its growth, including new and unmet electricity demand, advances in generation technologies, and developments in international finance that all facilitate investments in private power. The Asian financial crisis has put a break on the fast development of IPPs. But like the crisis, this is temporary. The continuing privatization and restructuring, particularly the introduction of competition in all segments of the electricity industry, will further IPP development. The transition to competition, however, raised some challenges to be overcome.

I. INTRODUCTION

The 1978 Public Utilities Regulatory Policy Act (PURPA) of the U.S. gave birth to the IPP industry. The law, which allowed U.S. electric utilities to purchase from small generators, or qualifying facilities (QFs), was a break from the traditional electric utility regulation and from an old view that electricity generation is a natural monopoly and could not be separated from transmission and distribution. The industry was born alongside the development of small generation technologies, particularly the gas turbine combined cycle (GTCC), which actually facilitated its growth. Since then, IPPs have flourished in the U.S. and have spread worldwide in their search for new markets outside the U.S. Private power generation has become a global industry, and Asia has become its most dynamic market.

The Asian financial crisis in 1997, however, has put a break on IPP growth, cancelling and postponing IPP projects, but generated new ways on contracting with private power, particularly in terms of risk allocation. Meanwhile, the financial crisis has renewed efforts toward increasing competition in the electricity sector. This transition has also raised some challenges to IPPs.

This paper reviews the development of IPPs and examines the issues that have influenced their growth and future challenges.

* Paper to be presented at "The Clean and Efficient Use of Fossil Energy for Power Generation in Thailand," The Joint Eighth APEC Clean Fossil Energy Technical Seminar and Seventh APEC Coal Flow Seminar, APEC Clean Fossil Energy Experts' Group, Bangkok, Thailand, 30 October – 3 November 2000.

II. GROWTH OF IPPs IN THE CONTEXT OF POWER SECTOR REFORMS

Most IPPs are indeed in the large U.S. market, which now hosts 230 IPPs[1] (see also Figure 1). In 1998, non-utility capacity totalled 98,085 MW, or 12% of the country's existing capacity that year, and generated 407 billion kWh, or 11% of the national total (from only 5% in 1986). Moreover, non-utilities have planned to add 61,456 MW from 1999-2003, which is more than double the 27,943 MW planned by the utilities in the same period. There are also several IPPs in Canada, though their contribution is relatively minimal. As of 1994, IPPs owned about 1% of installed capacity and produced 1.3% of total generation, which was sold entirely to utilities. Overall, the North American market hosts nearly 70% of the IPPs worldwide.

In the 1990s, however, IPP projects have been mostly located and growing fastest in Asia-Pacific which hosts 17% of the IPPs worldwide. Table 1 indicates that about half of the global IPP projects in 1996 and 1997 were in Asia-Pacific.

Table 1 also indicates that IPPs experienced strong growth in Latin America during this two-year period, even if the region accounts for just around 1% of IPPs worldwide.

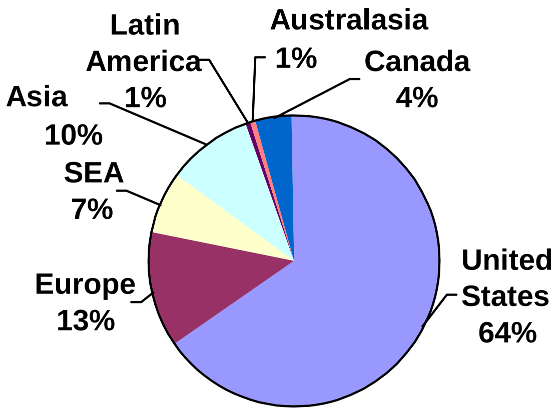

Figure 1: Geographical Distribution of IPPs in 1997

Source: Hughes and Parag (1997)

Table 1: IPP Project Finance in 1996 and 1997

	Number of projects		Total cost (US$ million)		Capacity (MW)	
	1996	**1997**	**1996**	**1997**	**1996**	**1997**
Asia-Pacific	26	29	9,703	15,430	8,962	13,944
North America	6	8	802	407	953	406
Europe	11	6	7,316	2,695	4,622	3,223
Africa/Middle East	-	2	-	1,682	-	1,536
Latin America	8	14	2,623	2,260	2,356	3,142
Total	**51**	**57**	**20,443**	**20,791**	**16,893**	**20,715**

Sources: Burr (1998); Anderson and Burr (1997)

A survey of equipment manufacturers in 1996 also showed the Asian and Latin American market standing out. Asia, including Southeast Asia, Central Asia and Russia, accounted for 40% of

[1] *PEI*, Dec 1999.

equipment orders by megawatts in 1996, equivalent to 10,559 MW.[2] Latin America, with 6,840 MW, accounted for 26%. Equipment orders in Europe, the Middle East and Africa together totalled 6,036 MW for a 23% share. The United States and Canada accounted for only 10%, or 2,743 MW, of all orders in 1996.

Industry analysts and observers note, however, that the North American market will rebound with the deregulation of the electricity markets in this region. The ageing generating capacity in the US will also open up opportunities for future IPP growth in this mature market.

In Asia-Pacific, China, the Philippines, Australia, Malaysia, and Indonesia host the most number of IPP projects (Table 2).

Table 2: Status of IPPs in Asia-Pacific in 1998

Countries	Number in operation (GW)	Number under construction or development (GW)	Number planned or under consideration (GW)
Australia	9 (3.3)	2 (0.2)	15 (4.6)
China	26 (6.6)	14 (10)	61 (75)
Indonesia	5 (0.78)	9 (10)	31 (23.7)
Japan		3 (0.018)	(5.7)[b]
Malaysia	9 (4.3)		6 (5.3)
New Zealand	3 (0.2)		6 (0.847)[a]
Philippines	33 (5.2)[d]	4 (1.2)	18 (4.1)
South Korea			(6.25)[c]
Taipei, China[h]	1(0.6)	8 (8.55)	
Thailand[f]		7 (5.9)	(12.5)[e]
Vietnam		6 (2.315)[i]	(>7.2)[g]

Notes:

a two are planned with a capacity of 0.385 GW and four are under consideration, 0.462 GW
b planned by 2004, 2.6 GW in phase 1 and 3.1 GW in phase 2
c the current policy limits IPPs to add up to 6.250 GW of capacity by 2010
d including rehabilitated projects and operated and maintained or leased to private sector
e up to 2011
f excluding small power producers, cross-border projects, and generation subsidiaries that are implemented by the private sector
g all the 7.2 GW capacity are combined cycle and excludes hydro projects that are likely to be offered for BOT financing
h three of the ongoing projects are due for commercial operation in 1999; three of the nine projects, including the one already operating, will be running on gas, another three on coal, two on orimulsion, and one on oil
i two of these projects, with a combined capacity of 495 MW, are expected to come on stream in 1999; both are oil based; three of the four remaining projects, with a combined capacity of 912 MW, will run on natural gas

Source: CEERD (1999); Carson (1998)

Ultimately, the birth and growth of IPPs can be traced to the continuing reforms in the electricity sector. In this regard, the electricity sectors in the APEC economies are at different stages of

[2] Anderson (1997)

privatization and restructuring (Figure 2). Few are in the most advanced stage of having privatized all electricity sector functions (generation, transmission, and distribution) and at the same time introduced wholesale and retail competition in the supply of electricity. The economies that have introduced retail competition (electricity users can choose their suppliers) include Australia[3], Chile, and Peru. New Zealand[4] and Singapore[5] have also introduced limited retail competition, but generation and transmission remain in the hands of state-owned corporations, although it is certain that these will be privatized in the future. Some of the states in the United States have introduced retail competition, but the transition to this stage is still being debated at the federal level. In all states, however, wholesale competition is mandated by the federal government by allowing third party (open) access to transmission networks. In the Alberta province of Canada, wholesale competition is also already a reality with operation of a power pool since 1996, the first in North America. Alberta is also preparing for full customer choice by 1 January 2001.

Majority of the APEC economies has introduced competition in generation by allowing non-utility generation, but the electricity sectors in these economies remain in the hands of state-owned utilities. The only exception is Japan, which is served by private vertically- integrated utilities. Most of these economies are in the transition to privatizing their electric utilities and introducing competition in wholesale electricity supply. These include Indonesia, Malaysia, Philippines, Thailand, South Korea, and even China. The other provinces in Canada, particularly Ontario, which are served by a mix of publicly- and privately-owned utilities, would soon be seen following the moves of Alberta.[6] Taiwan has scheduled the privatization of its electric monopoly, Taipower, but there is no indication that it will introduce wholesale competition in the foreseeable future. Mexico and Vietnam are perceived to remain in the hands of electric monopolies for some time, but are big markets for private power developers.

Papua New Guinea, Russia, and Hong Kong are the only three countries that have not introduced competition in generation..

The entry of IPPs in generation has become almost a necessity in the transition of electricity sectors from being dominated by vertically-integrated government monopolies to one characterized by competition. It is only in a few cases in which competition was introduced by emphasizing privatization of existing generation assets (for example, Australia, Chile, and New Zealand) and even in these instances, the entry of IPPs becomes inevitable.[7] In most cases, particularly in developing countries with strong electricity demand and limited financial resources, IPPs serve to fill the electricity-supply demand gap and ease the financial burden of

[3] The National Electricity Market (NEM) has been operating since 13 December 1998, following the operation of state markets in New South Wales, Queensland and Victoria, and will also include South Australia and the Australian Capital Territory (ACT), with the possibility of an expansion into Tasmania following its grid interconnection. Western Australia and the Northern Territory will not participate in the market due to geographical and cost factors. All consumers become contestable (can choose their supplier) by 1 January 2001 in the ACT, NSW, Queensland, and Victoria, and by 2003 in South Australia.

[4] The Electricity Corporation of New Zealand (ECNZ) was split into three state-owned generators on 1 April 1999. On 30 November 1998, the government announced that it would sell Contact Energy, another state-owned generation company, through a 60% public share float combined with a cornerstone share sale of 40%. Edison Mission Energy successfully bid US$1.208 billion for the 40% cornerstone shareholding and the public share float closed May 1999. After the sale of Contact Energy, the private sector generated 40% of total generation in New Zealand (Ministry of Economic Development, June 2000)

[5] A "pool and settlement system" was introduced in April 1998, and in principle allows electricity consumers whose demand exceeds 5 MW to choose their supplier. At the moment, however, this is not yet happening because there is only one supplier, Power Supply, a subsidiary of Singapore Power.

[6] Wholesale competition will be introduced in Ontario in 2001.

[7] Also, by definition, privatized generation assets are considered IPPs.

state-owned electric utilities. The entry of IPPs in these instances paves the way for further reforms and contributes to increasing the competitiveness of the electricity sector.[8]

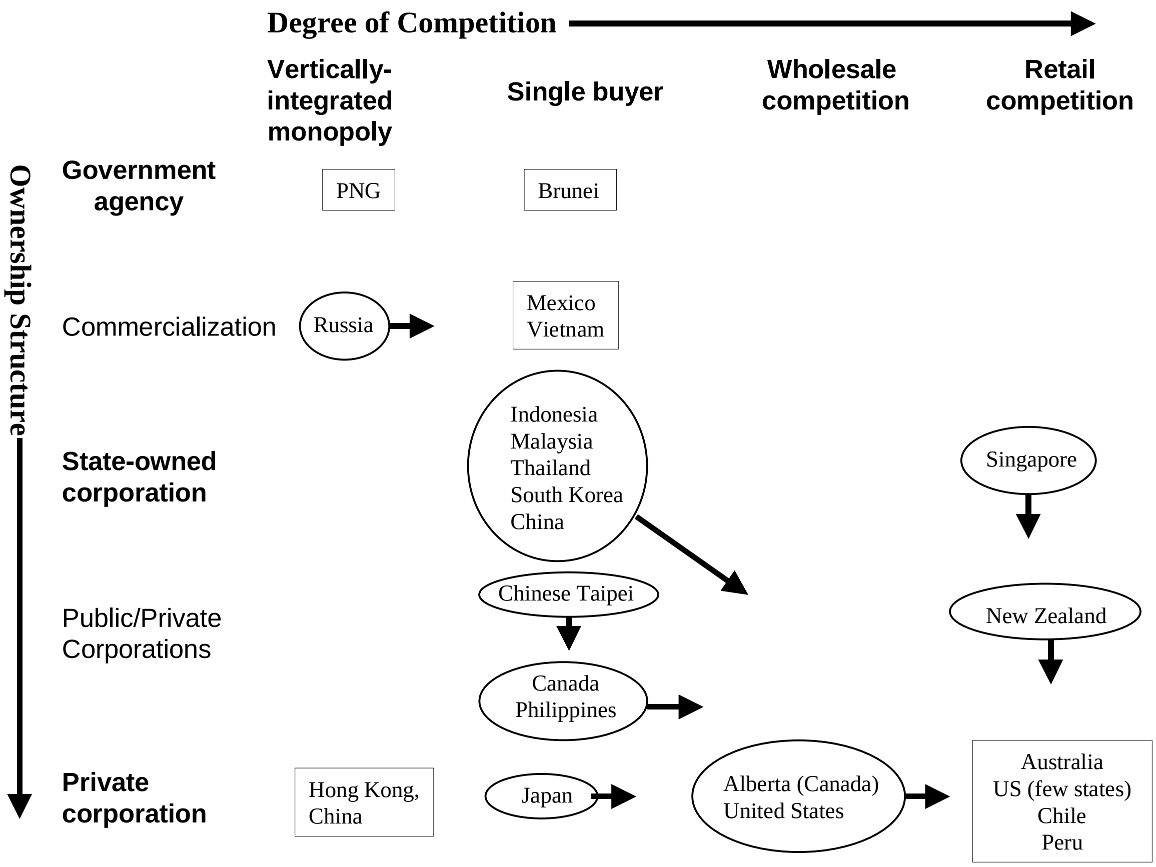

Figure 2: Status of Restructuring and Privatization in APEC Economies

Sources: APERC (2000); CEERD (1999); various other publications. The classifications are adapted from Hunt and Shuttleworth (1996).

III. OTHER DRIVING FORCES

Ultimately, the growth of IPPs can be traced to the transition of the electricity sector to more competitive arrangement and the changing ownership structures. But other factors have also influenced the growth of IPPs, including:[9]

- new and unmet electricity demand;
- advances in technology; and
- trends in international finance.

Electricity Demand

IPPs supply new and unmet electricity demand. The Asia Pacific Energy Research Center (APERC) projects that Southeast Asia will start to recover from the crisis after 2000 and would register an annual average economic growth of 4.3% between 2001 and 2010.[10] China, which remains isolated from the crisis, would grow between 4.4% and 4.6% annually in the same period.

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[8] See for example Roseman and Malhotra (1996).
[9] See Simon (1996).
[10] APERC (1998).

Chile and Mexico are expected to continue to grow 4-6% in the next ten years. In most of these countries, entrenched government utilities are unable to sustain needed investments in generating capacity and power infrastructures. Yet even in developed APEC member countries, opportunities for independent power investment are present because of expected increase in electricity demand, also arising from economic growth. For example, in Australia, Canada, and New Zealand, APERC projects electricity demand to grow in the range of 2.5% to 4% in 2000-2010.

Unmet electricity demand, on the other hand, is shown by the low per capita electricity consumption and low electrification rates among the developing member-economies of APEC. Chile, Malaysia, and Thailand, for example, had per capita electricity consumption below 2,000 kWh in 1996. The situation is worse in Indonesia, Philippines, and Vietnam, which had per capita electricity consumption of less than 500 kWh. China and Peru, consuming 637 kWh and 525 kWh, respectively, per person in 1996, are somewhere in between. This is well beyond that in the U.S. and Canada, which is in the range of 11,000 – 15,000 kWh per person. Japan, Singapore, South Korea, Taiwan and Australia are in the 6,000 – 8,000 kWh range.

The electrification rates in some of these countries are also low, contributing to the low per capita electricity consumption and indicating not only the need for increased generating capacity, but more importantly for expanded electricity infrastructures (transmission and distribution networks and decentralized energy systems). For example, the proportion of households that have access to electricity in Indonesia, Papua New Guinea, and Vietnam in 1994 is below 50%.

Advances in Technology

The development of small generation technologies, in contrast to large power plants of government-owned utilities, has facilitated investment in private power. This technological breakthrough has reduced the financing requirements and risks associated with large power stations. Natural gas-fired technologies are attractive not only because of their size, but more so because of their high efficiency (GTCC has surpassed the 50% mark and has reached the 60% threshold), shorter construction schedules, low capital cost, and because they use natural gas, which has lower environmental emissions than oil and coal. On the other hand, the continual improvements in clean coal technologies are increasing the opportunities for IPPs to tap markets with indigenous supply of coal, or where coal is the most competitive option, and, at the same time, comply with increasing national and international environmental standards.

Natural Gas Technologies

The conventional technologies for natural gas-fired power plant include gas turbine, gas-fired steam units, and combined cycle. The advanced type of natural gas technologies includes inter-cooled steam injected gas turbine (ISIGT) and fuel cells power plant.

Summary data on the technical and economic potential of these key natural gas technologies are presented in Table 3.

Gas-fired, gas turbine and combined cycle technologies are commercially available, and the gas-fired technology is currently being superseded by more efficient technologies (i.e. combined cycles). ISTIG and fuel cells are in demonstration stage and are undergoing continuous development.

Among the conventional technologies, the combined cycle is the most efficient, achieving 43%-58% efficiency, and might be up to 60% in the near future. The efficiency for gas turbine technology is typically from 30% to 37%, but it can be as high as 42% for new gas turbine models. The advanced types of gas technologies have the potential to achieve from 47% to 60% efficiency.

In terms of costs, among the gas technologies, gas turbine is the cheapest technology (US$250-600/kW) and fuel cell is the most expensive one (US$580-2100/kW). The capital costs of combined cycle technologies are in between (around US$480-600/kW).

Table 3: Technical and Economic Status of Natural gas Technologies

Technology	Status	Conversion Efficiency %	Capital Cost (US$/kW)	Emission (g/kWh)		
				CO_2	NOx	CO
Gas-fired steam	Commercial	30-37	790	500	0.8	0.07
Gas Combined Cycle	Commercial	43-58	480-600	425	0.4-1.3	0.07-0.12
Gas combustion turbine	Commercial	30-42	250-600	525	0.4-1.8	0.15
Fuel Cells	Demonstrated/R&D	40-60	580-2100	290-520	0.11	0.07
Intercooled Steam Injected Gas Turbine (ISIGT)	Demonstrated/R&D	42-47	900-1100	100	0.04	0.2

Source: The GREENTIE Directory

Natural gas normally has little or no sulphur. Therefore flue gas desulphurisation systems are not needed. However, as with coal-fired plants, nitrogen oxides are produced during the combustion process. Low NOx burners can partially reduce the production of NOx in gas turbine combustors can also be used to reduce NOx production, but this reduces thermal efficiency and so is less common in new machines. In areas where strict NOx emission regulations are in effect, additional measures are normally needed. Post-combustion systems, mainly selective catalytic reduction, can be used.

Clean Coal Technologies

Clean coal technologies form the foundation for a new generation of coal-fired power plants. These technologies enable coal utilization to be extremely clean, greatly reducing concerns about many pollutants and dramatically reducing the emission of greenhouse gases.

Clean coal technologies can be installed at any of the three functional stages in the coal chain, or in a fourth manner that departs from the traditional method of coal burning. These are pre-combustion, combustion, post-combustion and conversion technologies. The coal can be cleaned by pre-combustion technologies before it burns. The pollutants inside the combustor or boiler can also be removed by combustion technologies while coal burns. Post combustion technologies on the other hand, can reduce the amount of particulate, sulfur oxides and nitrogen oxides in the equipment leading to the stack. Lastly, conversion technologies bypass the combustion altogether, changing coal into a clean natural gas or liquid that can be used as a fuel. It allows pollutants in the coal to be removed economically and effectively prior to combustion.

Combustion Technologies

A summary data on the technical and economic potential of key coal combustion technologies are presented in Table 4.

The conventional coal power plant uses subcritical pulverized fuel combustion (PF). Over most of the world, subcritical PF is the predominant coal technology. It is a well proven technology with over 40 years of operational experience. Super critical pulverized fired plant is a substantially proven technology which is used in a few countries. Ultra-supercritical PF technology is still under development. The advanced clean coal technologies that are being developed include

Atmospheric Fluidized Bed Combustion (AFBC); Pressurized Fluidized Bed Combustion (PFBC); and Integrated Gasification Combined Cycle (IGCC) technologies. The coal combustion technologies differ in terms of efficiency, costs and emission reduction.

Table 4: Technical and Economic Status of Coal Combustion Technologies

Criteria	Subcritical PF	Supercritical PF	AFBC	PFBC	IGCC
Maturity of Technology	Completely proven	Substantially proven	Proven at small scale (<200 mw) only	Only five commercial units built, limited experience	Only one commercial unit
Range of Unit Size Available	All commercial size available	All commercial sizes available	Small units only at present	Currently limited to two sizes	Currently limited to large gas turbine units
Fuel flexibility	Burns a wide range of coals, but less efficient than FBC at extremes of moisture/ash	Burns a wide range of coals, but less efficient than FBC at extremes of moisture/ash	Will burn practically anything that can be burned	Should burn same range as AFBC, but not proven	Should use wide range of coals, but not proven
Thermal Efficiency	36-38% Limited by steam conditions	40-46% High, further increase depends on materials development	34-40% Relatively low, but supercritical steam conditions will raise efficiency	42-45% Second generation PFBC has higher efficiency	43-48% High, further increases as gas turbines improve
Operational Flexibility	Performance limited at low load	Performance limited at low load	Wide load range and response	Potentially similar to PF but needs proof	Limited experience, needs demonstration*
Environmental Performance	Low efficiency and FGD solids a problem	Better than subcritical because of higher efficiency	Low efficiency and large volume of solids	Good, but solids residues a potential problem	Excellent, inert slag, sulfur recovered in elemental form
Availability	Proven to be excellent	Proven to be good	Limited experience at utility scale	Limited experience	Limited experience, results modest so far
Build time	On-site installation required	On-site installation required	On-site installation required, but no FGD required	Long so far, but substantial opportunity for modularisation	Long so far, but opportunity for shop fabrication of major items
Current specific capital cost	US$900-1300 /kW Cheapest	US$950-1600 /kW Medium	US$1000-1600/kW Potentially cheaper than PF+FGD	US$1100-1500/kW Expensive	US$1200-1600/kW Most expensive

Note: Thermal efficiency is the net efficiency based on the lower heating value of the fuel
Source: IEA (1996); IEA (1997b)

The conventional coal technologies have a thermal efficiency in the range of 36-38% (net, lower heating value (LHV) basis). The advanced clean coal technologies can achieve higher efficiency than the conventional technologies. Among the advanced coal technologies, IGCC is the most efficient, achieving 43-48% efficiency (net, LHV). The efficiency for AFBC is relatively low, ranging from 34% to 40%. Supercritical PF and PFBC can also achieve higher efficiency, ranging from 40% to 46%. Most of advanced clean coal technologies are capable of higher efficiencies with values of up to 50% achievable with further development.

In terms of costs, among the coal technologies, the subcritical PF is the cheapest technology (US$900-1300/kW) and IGCC is the most expensive one (US$1000-1800/kW). The capital costs of AFBC and PFBC are in between (around US$1000-1600/kW), but AFBC has the potential to be less expensive than conventional coal technology with FGD emission control. The costs of supercritical PF technologies range from US$950/kW to US$1600/kW.

Without emission control, 80% of the ash, 90% of the sulphur in coal and 90% of the NOx are emitted during combustion for conventional technology .[11] Advanced clean coal technologies can reduce by more than 90% of SOx and 60% of NOx emitted during combustion. Among these technologies, IGCC is the most effective technology that can reduce both of SO2 and NOx emissions by 98%.

Trends in International Finance

Changes in the policies of international development banks as well as the globalization of capital markets are also facilitating the growth of investments in independent energy.

<u>Changes in Multilateral Banks Lending Policies</u>

In many developing countries, including members of APEC, multilateral banks (the World Bank and ADB) are usually the architects of electricity sector reforms. In some cases, they encourage policy-makers to institute reforms by financing technical assistance studies that are mainly aimed at informing and convincing high and middle level officials of the benefits of reforms. More often than not, these technical assistance studies are coupled with institutional strengthening activities designed to inculcate the necessary competence among middle level officials and their staff, including attached government agencies, to properly execute recommended reforms. In recent years, however, multilateral banks have taken a proactive stance to somehow “force” governments to institute reforms.

The World Bank, for instance, which allocates nearly 15% of its development funds to the power sector, issued a policy paper in 1993 that states that the bank is not prepared to lend to countries unless they are prepared to undertake a program of reforms. The key elements of those reforms are the introduction of more competitive pressures and more market oriented systems, open regulatory structures, pricing that covers costs, and the elimination of elaborate systems of cross subsidies. In the Asian Development (ADB), the main focus of their energy activities is in reforming government policies, determining correct pricing of power and in assisting in implementing institutional improvements.

Another way by which multilateral banks have encouraged the growth of IPPs is by introducing private sector financing in their portfolio. This means multilateral banks finance private power projects by contributing equity or extending loans—a departure from their traditional role of lending to development and public infrastructure projects sponsored by the government. The World Bank does this through the International Finance Corporation (IFC), which can extend loans and invest equity capital to private sector projects without government guarantee. The ADB has a stake in an affiliate institution called the Asian Finance and Investment Corporation (AFIC),

[11] APEC (1997).

which functions similarly as IFC. In 1983, ADB began making equity investments to private sector companies. Since then, it has expanded its private sector operations by establishing a Private Sector Department that make equity contributions and provide direct loans to private entities, including IPPs.

Globalization of Capital Markets

The rise of global capital markets has facilitated the financing of private power projects. *Independent Energy* reported in its annual rankings of financial institutions, which invest and lend to and arrange deals for private power projects, that revenue bond issues in 1996 tripled those in 1995, increasing from US$5 billion to nearly US$15 billion.[12] Increased access to international capital markets is one reason for this increased bond activity. Another is the attractiveness of bonds because of their longer- term maturity, some up to 20 years. A third reason is that capital markets provide a vast, additional source of financing for an industry with huge financing requirements.

IV. IMPACT OF THE ASIAN FINANCIAL CRISIS

The financial crisis that started in Southeast Asia in 1997 has, however, put a break on IPP development. In particular, the crisis affected independent power in terms of:[13]

- increased cost of power;
- contraction of the market; and
- threats of contract defaults and renegotiations.

Cost of Power

The financial crisis had been sparked by the devaluation of the Thai baht, which spread swiftly in East Asia and resulted in the sharp depreciation of most currencies in the region. Naturally, the immediate impact of this is to increase domestic prices of goods that have high import content, electricity among them. The magnitude of the increase attributable to private power depended on many factors, including the dimensions of the crisis, origin of fuel supply, currency denomination of the bulk supply tariff, source of financing, the amount and timing of private power purchases and the relationship between wholesale and retail tariffs. These factors are enumerated in Table 5 and are examined for the countries worst affected by the crisis.

Thus, Table 5, for example, explains why Indonesia's IPPs suffered most from the crisis. Except for fuel supply that is indigenous, all factors have increased the risk of default by the national utility and led to the cancellation of several private power projects. For example, as IPP payments were denominated in hard currency and retail tariffs did not provide enough margin to cover high wholesale tariff, the sharp drop in the rupiah has made it difficult for PLN, the national utility, to meet its obligations. This was compounded by the facts that several contracted projects were in the pipeline and that these projects are mostly financed by foreign sources.

[12] Burr (1997)
[13] Gray and Schuster (1998).

Table 5: Determinants of the Impact of Financial Crisis on Private Power

	Indonesia	**Malaysia**	**Philippines**	**Thailand**
Dimensions of the economic crisis	• the rupiah dropped 80% in value • interest rates soared three times higher than pre-crisis levels • stock market fell by 40% • sharp economic contraction in 1998	market index fell by more than 50% in local currency terms between early June 1997 and 1998	market index fell by 30% in the same period	market index fell by 40% in the same period
Origin of fuel supply	indigenous	indigenous	imported	imported
Currency denomination of the wholesale tariff	IPP payments denominated in hard currency	IPP payments denominated in local currency	IPP payments denominated in hard currency	IPP payments denominated in local currency
Extent of domestic financing	14%	90%	3%	75%
Amount and timing of private power purchases*	• has nearly 5 GW of private power capacity under construction or in operation • accounts for nearly half the new IPP capacity due to begin operation in these countries in 1998-2001 • more than 9,000 MW under construction or at an advanced stage of development	• nearly 5 GW of private power in operation and few under construction • relatively little new IPP expected by 2001	• more than 3 GW in operation and about 1 GW under construction • relatively little new IPP expected by 2001 • more are under development and expected to come on-stream after 2002	• more than 2 GW in operation (small power producers) or under construction • first major IPP will be operation only in 1999
Relationship between wholesale and retail tariffs	retail tariffs not adequate to provide margin for high wholesale IPP tariffs	wholesale IPP tariffs range from 3c to 4c per kWh and retail tariffs provide adequate margin	wholesale tariffs relatively high and retail tariffs not sufficient to cover cost of operations	same as in Malaysia

* as of March 1998

Source: Summarized from Gray and Schuster (1998).

Electricity Demand

Prior to the crisis, electricity demand expectations were high, explaining in fact the opening of the electricity sectors to IPPs to finance and build expensive power plants. The financial crisis checked those expectations and even curtailed electricity demand. Thus, many countries in the region would face a situation of oversupply, at least until 2005, and have had to adjust their supply expansion plans. As a result, a number of private power projects have been delayed or cancelled (Table 6).

Table 6: Effect of the Financial Crisis on Expected New Greenfield Private Power Projects, 1998-2001 (Gigawatts)

		Post-crisis projections	
Country	**Pre-crisis projections**	**Low-growth scenario**	**High-growth scenario**
Indonesia	7.3	3.8	4.0
Malaysia	1.4	0.1	0.5
Philippines	3.6	2.8	3.3
Thailand	3.8	0.2	2.0
Total	**16.1**	**6.9**	**9.8**

Source: Gray and Schuster (1998)

In Thailand, for one, demand forecasts was revised twice because of the crisis. Forecast electricity (peak) demand growth between 1996 and 2001 is now less than half from pre-crisis forecast, from almost 10% in the October 1996 forecast to just 4.0% in the latest September 1998 forecast. In fact, peak demand contracted by 2.25% in 1998, after growing 8.98% in 1997. As a result, the construction of at least three EGAT power plants has been delayed; two of them by four years. All IPP projects, with a combined capacity of more than 5,900 MW, have been delayed. EGAT, moreover, has indefinitely postponed the second round IPP solicitation. The Government has also postponed the power purchase from SPPs for a firm capacity of 2,097 MW during 1996-2003. EGAT also decided to delay the purchase of 1,600 MW from Lao PDR until 2006 and an additional 1,700 MW by 2008.

In Malaysia, the plan to build a 2,400 MW hydropower plant has been shelved owing to cost increases arising from the ringgit's depreciation. Tenaga Nasional Berhad (TNB), Malaysia's national power utility, has also postponed several non-essential transmission and distribution projects. Another coal-fired power plant on Penang Island has been postponed indefinitely owing to increased construction costs. Malaysia is projected to be in surplus situation until 2001.

In Indonesia, the crisis cancelled the contracts of 27 IPP projects with a combined capacity of at least 11,265 MW, which is equivalent to 65 per cent of the country's total installed capacity in 1997.[14] Thailand and Indonesia will not have any demand for new capacity until 2005.

The crisis did not have a large impact, though, on the Philippines as few private power projects are targeted for commercial operation by 2001 (except for the commissioning of Hopewell's 1,000 MW Sual coal-fired plant in 1999). Moreover, the Government has assumed a fairly substantial portion of the risks through sovereign guarantees, and including all fuel supply, inflation and foreign exchange risks. Its willingness to assume these risks was important to the

[14] To date, Indonesia has agreed to drop the legal action (filed by the Habibie government) against the 27 IPPs contracted by the Suharto government. Instead, the current government of President Abdurrahman Wahid would re-negotiate. (*PEI*, p13, Jan/Feb 2000)

successful financing of several early projects.[15] Philippines will have a surplus capacity until 2004.

Contracts and Risks Allocation

The sharp devaluation of the local currency in these countries has two immediate consequences on the contracts between IPPs and the national power utilities, or power purchase agreements (PPAs). First, IPP contracts specify take-or-pay conditions on the amount of electricity it will sell to national power utilities. The financial crisis has increased the risk of not meeting projected electricity demand (market risk), and made many private power projects redundant. Second, payments to IPPs are usually denominated in US dollars, but national utilities are paid by customers in local currency (foreign exchange risk). The financial crisis, therefore, multiplied the local currency requirements to meet foreign exchange obligations of national utilities. In both cases, the national power utilities face a financially disastrous situation, as they have assumed a greater portion of both the market and foreign exchange risks.

The financial crisis, therefore, stimulated the re-examination of private power contracts, particularly in terms of risk allocation.

There are three principal dimensions to the (power purchase agreement) PPA:

- the selling prices for power and energy;
- the amount of power and energy sold; and
- incentives to improve performance and disincentives to ensure that performance does not fall below certain standard.

The experience in the face of the financial crisis in 1997 and 1998 shows that there are flaws in the existing commercial arrangements in the electricity sector in Asia that made them vulnerable to the financial crisis. In most cases, private power projects have been built with financing raised in hard currency, and then operated where cash flow is generated in local currency. This is the case, especially, of Indonesia and the Philippines in which IPP payments are denominated in hard currency and in which foreign financing constitutes 85% to 97% of the project financing. In most instances also, governments have assumed many of the risks associated with private power projects even if they are not in a strong position to bear such risks. Two such risks relate to foreign exchange fluctuations and energy demand—the two most important economic variables affected by the financial crisis.

Currency devaluations have important effects:

- erode utility's or project's ability to service debt;
- could raise operating costs, especially if the imported component of the project is high;
- for projects under construction, could increase the cost of procurement of imported machinery

At first glance, it may appear that governments should assume the risks associated with currency exposures because they have some control over exchange rates (and interest rates), and, if they take on these risks, they will have incentive to follow stable macroeconomic policies.[16] There are a number of reasons, however, why investors should bear exchange and interest rates risks:[17]

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[15] The Philippines had little bargaining power when it signed these early private power projects (between 1991 and 1993) as it was confronted by a power crisis. Now that the power supply situation has stabilized, the Philippines is passing on some of these risks to private power producers.

[16] Currency risk can be broken into currency transfer risk and currency exchange-rate risk.[16] Transfer risk, also called conversion risk, generally refers to the ability and willingness of the sovereign government to allow its currency to be converted into a foreign currency. Transfer risk is present when an issuer needs to convert the currency in which it receives revenues (usually the local currency or currency of the issuer)

- government guarantees may encourage investors to take large exposures to exchange and interest rate risks;
- exchange rate guarantees may have an adverse influence on government behavior, for example, they might discourage a government from allowing a needed depreciation of the domestic currency following a terms of trade shock;
- many governments—and the taxpayers who support them—are already exposed to the risks associated with exchange and interest rate shocks; and
- in the absence of a government guarantee, the private sector might have more incentive to manage exchange rate risk.

In addition, government guarantees threaten to undermine the benefits of privatization or private sector financing of infrastructure in a number of ways:[18]

- if the government assumes the risk of project failure—for example, by guaranteeing demand for the services provided—private investors have little incentive to choose financially sound projects and to manage them efficiently;
- guarantees may impose excessive costs on the host country's taxpayers or consumers;
- the issuance of guarantees could lead to a fiscal crisis by encouraging investors to take excessive risks.

On the other hand, to attract private investments in the electricity sector, many governments, through state-owned electric utilities, have entered into long-term take-or-pay contracts with IPPs, guaranteeing their energy sales. At the time these PPAs were signed the economic prospects of the region were very bright, and consequently, energy demand expectations were high. This tended to justify the assumption by governments of risks associated with a fall in energy demand.

> "In general, the dynamic economic climate and prodigious demand for electricity in Asia implies that the no-take risk is small in the region and investor apprehension on this score is unwarranted—it is, more often, a bargaining chip than a real concern."[19]

The experience of the recent financial crisis proved these expectations to be overly optimistic and the assumption by purchasing government electric utilities of energy demand risks unjustified. Thus, the resulting situation called for the renegotiation of these power contracts. In general, this means converting the existing PPAs to more competitive arrangements. (See Appendix 2.)

V. IMPLICATIONS OF THE TRANSITION TO WHOLESALE AND RETAIL COMPETITION

The financial crisis provided an opportunity for Asian economies to renew and intensify efforts to move towards more competitive arrangements in the electricity sector. The Asian IPP market is being transformed into a more transparent and competitive system based on the power pool models that have been implemented in the UK, Australia, and some parts of the USA. These models separate the generation, transmission, and distribution functions and dismantle national monopolies, particularly in generation. At the same time, generation assets are being handed over to private investors. However, there are at least two issues that would impact on IPPs: PPAs and stranded cost and transition of IPPs into merchant power plants.

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into a foreign currency. Exchange rate risk, on the other hand, is the changes in the value of the local currency relative to another (the hard currency).

[17] Thobani (1999).

[18] Ibid.

[19] David and Fernando (1995.

PPAs and Stranded Cost

The transition to competition raises three issues concerning its consequences to the power purchase agreements with IPPs:[20]

- What should happen to the PPAs?
- Who should hold the resulting contract?
- How should any surplus or deficit arising from a difference in the pool price and the contract price be handled?

One answer to the first question is doing nothing, to leave the PPAs unchanged in terms of structure.

A second possibility is to ask the IPPs to give up their PPAs. However, their willingness to do so will depend on:[21]

- the expected divergence between the pool price and the PPA price;
- the expected length of time that a divergence will exist;
- the discount rate applied by the IPPs;
- the sensitivity of the result to small changes in the assumptions, such as an unexpected slowing-down in the growth rate of the economy;[22] and
- the expectation that there will be a shift to a better technology for generating electricity that will place the existing plant to a competitive disadvantage vis-à-vis a new plant.

A third option is to convert the PPA into a Contract-for-Differences (CfD).

> Cfd is a financial instrument designed to allow generating companies, and customers, participating in a competitive electricity market to enjoy the revenue stability afforded by a PPA without necessitating the inflexibility of a PPA in terms of the price that is bid into the pool. A CfD works through the generating company agreeing with a customer (although a speculator or third party could also be involved) a fixed price (the strike price) for its electricity, and then a settlement is reached according to whether the pool price was actually higher or lower than the fixed price. If it is higher then the generating company pays the difference to the customer, while if the pool price is lower than the fixed price, then the customer pays the difference to the company. So, it would be possible to establish CfDs that replicate the existing PPAs and so ensure that the generating companies are not financially worse off but are able to participate in the pool.[23]

Similarly, there is not one answer to the second and third questions. The resulting PPA or CfD can be held by the transmission company that is formed out of the vertically integrated electric utility, a special purpose holding company, or the distribution companies. Each of these options has implications for the operation of the market. On the other hand, to meet the difference between the pool and contracted price (in the original PPA), a levy can be imposed upon customers or funds can come from taxes (in case of a deficit) or go to the treasury (in case of a surplus).

IPPs to Merchant Power Plants

A pure merchant plant is a power plant built without guaranteed customers for the electricity generated by the plant. Developers bear the risk that they will be able to sell power to willing

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[20] London Economics (1997).
[21] Ibid.
[22] The experience of the Asian financial crisis will have led investors to give this factor greater weight than before.
[23] Ibid

buyers. Hybrid merchant plants benefit from having at least some portion of their output secured under contractual sales arrangements.

"The merchant trend started in the United Kingdom with the advent of wholesale power competition in 1990. It spread to Argentina, Chile, Australia, and other countries that adopted competitive bulk power supply systems. Now it is spreading to California, New England, Texas and other regions of the United States where competitive wholesale power generation is on the rise. Several dozen new merchant plants totaling more than 10 GW have been announced in the United States."[24]

Merchant plants sell to competitive power markets, in contrast to the traditional IPP projects that sell electricity to a utility through long-term power purchase agreements (PPAs). The move towards greater competition in the electricity markets of APEC economies will see the growth of merchant power plants, which could be existing projects whose long-term contracts have expired or new projects that sell part or all of electricity produced to the competitive market. Already, merchant power projects are in operation or under development in the United States and Australia and soon will rise in Chile, Peru, Singapore, and New Zealand. All these economies have introduced wholesale and limited retail competition.

Merchant power producers put high priority on reliable fuel supply. As against committing to a long-term fuel supply contract with fuel suppliers, merchant power sponsors prefer establishing long-term relationship with fuel suppliers who are willing to share price risks and take an equity position in the project. This situation is now more likely to happen than ever with the number of gas producers entering the business of power generation increasing. In addition, to minimize risks new merchant projects will tend to be running on natural gas because the plants can be built on a small scale.

The moves towards competition in electricity supply at the wholesale and retail levels will see a decrease in IPP contracts and the rise of merchant power plants (MPPs). Traditional IPPs differ from MPPs in a number of ways as shown below. The most important is the absence of contractual relationship between the merchant power producer and the buyer of electricity, implying more risks being assumed by the power developer.

Table 7: Traditional IPPs vs. Merchant Power Plants

Traditional IPPs	Merchant power plants
• Long-term PPAs	• No PPAs
• Predictable revenues	• Volatile revenues
• Stable fuel supply	• Possible stable fuel supply
• Isolated from competition	• Subjected to intense competition
• Fixed fuel-electricity spread	• Unpredictable operating margins

Source: Smock (1997)

VI. CONCLUDING REMARKS

The transition of the electricity sectors in APEC economies to more competitive arrangements will increase further the role of IPPs in meeting electricity demand. This time, however, IPPs should assume more risks than they have done under the traditional take or pay contracts with national utilities. One lesson of the Asian financial crisis is that this type of arrangement does not really protect IPPs from market and foreign exchange risks, but in fact increases the risk of default by national utilities. A shift to a more competitive arrangement would benefit both IPPs and utilities particularly as the electricity sectors are transformed into fully competitive markets.

[24] Smock (1997).

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APPENDIX 1: FUEL AND TECHNOLOGY CHOICE OF IPPS

IPPs have contributed to the changing fuel mix in power generation in APEC economies. Most IPP projects are using either coal or natural gas, which are the preferred fuels in many of the APEC economies. In the U.S., for instance, gas-fired plants account for more than 42% of non-utility capacity, while coal-fired plants, for 15%. Moreover, 60% of the planned non-utility capacity additions between 1998 and 2001, which represent at least half of the planned utility capacity additions during this period, will be using natural gas. Natural gas is also becoming popular among U.S. electric utilities. Gas-fired plants account for less than 20% of existing utility capacity, but for close to 90% of planned utility capacity additions between 1998 and 2007. IPPs in Australia and South Korea also prefer natural gas. In Australia, where coal contributes around 80% to total power generation, seven of the eight new power stations proposed during 1997 will be using natural gas. In South Korea, in which coal accounts for 35% of total power generation, three of the four IPP projects due to come on stream between 2001 and 2004 will burn LNG. Another block of 3,650 MW planned for 2005-2010 will be designed for LNG.

In China, the largest market for IPPs in Asia[25], coal remains as the most competitive fuel choice. Coal accounts for about 88% of total fuel consumption for power generation, and coal consumption for power generation is still growing between 9% and 10% per annum. The 2 x 350 MW Laibin B, which is the first BOT by Chinese standard and expected to come on-stream in October 1999, will be using coal. The 2 x 700 MW Zhuhai, which qualifies as a BOT by international standard and expected to be commissioned in 1999-2000, is a US$1.2 billion power project using coal. Shandong Zhonghua Power Co., the largest IPP to date and which reached financial closing in 1998, is building four coal-fired power plants with a combined capacity of 3,000 MW at a total cost of US$2.2 billion.[26]

In some countries, in which neither coal nor natural gas is the dominant fuel, IPPs are also choosing coal and natural gas. In Mexico, for example, which is the largest producer of oil in Latin America, the first two major IPP projects, the 484 MW Merida III and the 700 MW Samalayuca II, will be using gas-fired combined cycle technology. In addition, a number of gas field development projects are underway to supply to these two and future IPP projects. In New Zealand, in which hydropower contributes more than 70% of electricity produced, future IPP projects will be using natural gas. In the Philippines, which is predominantly oil-based, IPPs are choosing between coal and small hydro projects, and a few projects will tap indigenous natural gas supply.

Coal and natural gas combined account for at least 60% of total power generation in Australia, Brunei, China, Hong Kong, China, Indonesia, Malaysia, Russia, Singapore, Thailand, the United States, and Vietnam. These figures also show that there are as many APEC economies in which the share of natural gas (in the power generation mix) is greater than coal as those in which the share of coal is greater than natural gas, indicating the close competition between the two fuels. However, natural gas consumption for power generation is growing faster than that of coal, as well as total power generation, in more APEC economies, including those in which coal share in power generation is higher (that is, Australia, Canada, and Chinese Taipei). In China, South Korea, and the U.S., which uses much more coal, growth in natural gas consumption is rivalling that of coal. These trends indicate increasing preference for natural gas.

The choice of fuel dictates the choice of technology. With increasing preference for natural gas, gas turbines have been filling in the demand for new capacity worldwide. Steam turbines, however, remains popular in Asia, even though the region has consistently topped the market for gas turbine capacity additions.

Based on a survey of 10 major global power equipment suppliers conducted by *Independent Energy* in 1996, gas turbine is the preferred technology for new generation capacity worldwide.[27] The survey showed that out of 395 units ordered in 1996, 264 (or 67%) were gas turbines (Table

[25] There are four forms of IPPs in China: an equity joint-venture, a co-op joint venture, a wholly foreign-owned entity, and through investment in joint stock company. Most IPPs in China are co-op joint ventures as the structure allows more flexibility in recovering investment. (Carson, 1998)

[26] The principal sponsor of this project is CLP Power International (CLP-PI), part of China Light and Power group.

[27] Anderson (1997)

6.3). In terms of capacity, this represents 51% (or 18,170 MW) of the 35,807 MW total capacity ordered.

Nevertheless, an earlier survey also by *Independent Energy* shows that steam turbines seem to be the favorite in Asia.[28] The survey covered the period from January 1994 to May 1996 and 14 global power equipment companies that reported 107 GW in orders for steam turbines, gas turbines, heat-recovery steam generators, combustion boilers, and combustion engines. Steam turbines accounted for 50% of the total capacity orders, indicating preference for solid fuels. The 1996 survey tends to confirm this as China, the largest market for IPPs in Asia and where coal is the dominant fuel, got most orders for 21 units with a combined rating of 4,190 MW.

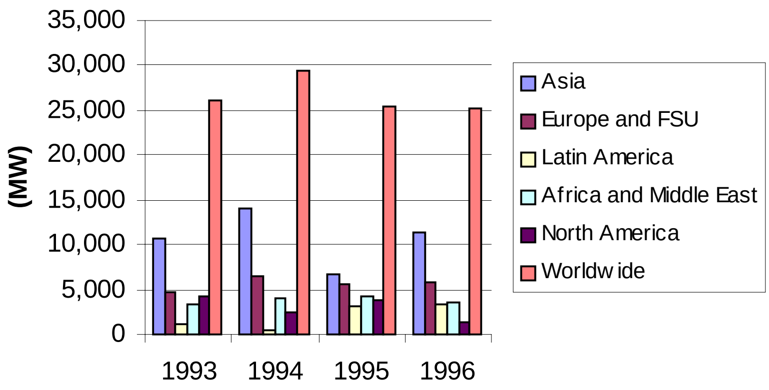

Figure A1: Gas Turbine Capacity Additions by Region

Source: Schuler (1997)

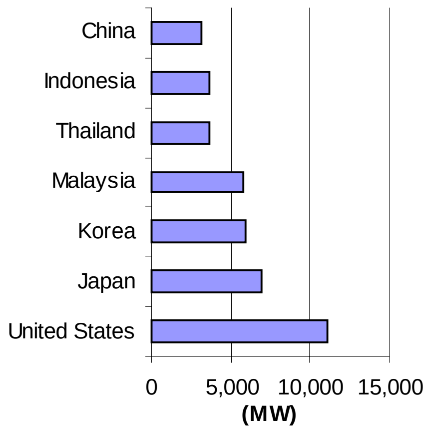

Figure A2: Gas Turbine Capacity Additions by Country, 1993-1996

Source: Schuler (1997)

[28] Burr (1996)

Table A1: Global Power Equipment Orders in 1996

Technology	Number of units	Capacity (MW)
Diesel	42	788
Gas turbine	264	18,170
HRSG	36	4,421
Steam turbine	53	12,428
Total	**395**	**35,807**

Source: Anderson (1997)

A survey of independent power projects that reached financial closing in 1997[29] also shows that coal-fired technologies still dominate the Asian as well as the Pacific power markets for new generation capacity. In China, for instance, of the four major projects listed in the survey, including Laibin B, three with a combined capacity of 4,120 MW are using coal. The other 400 MW project is running on gas. Australia had four projects with a total capacity of 5,239 MW fuelled by coal.

The picture in Asia, however, varies from country to country. In Thailand, for example, coal is competing closely with gas. Of the seven ongoing IPP projects expected to become operational between 1999 and 2003, four with a total capacity of 2,394.3 MW will be using gas, and the other three projects will run on coal, but with a higher combined capacity of 3,441 MW.

In the Philippines, of the more than 20 IPP greenfield projects commissioned since 1991, only one (the 700 MW Pagbilao plant by Hopewell) is coal-fired. Most are oil-based, and the rest are using either hydro or geothermal. Future projects, however, will fit coal and hydro. Already, another coal project by Hopewell with a capacity of 1,000 MW is scheduled to come on-stream in mid-1999. In addition, four smaller coal-fired projects with a total capacity of 525 MW are being considered as against several small and large hydro projects. Only three natural gas projects are in the pipeline, with a total capacity of 2,700 MW.

In Vietnam, all of the gas-fired combined cycle planned after 2005 through 2020 (with a total capacity of 7,200 MW) are candidate for BOT implementation. Moreover, most of the planned hydro projects (totaling 8,700 MW) will be offered for private development. These projects account for 53% of the planned capacity additions between 1998 and 2020.

The choice of fuel and technology by IPPs is driven by:

- the availability of fuel;
- relative fuel prices;
- attractiveness of the corresponding generation technology, in terms of:
- cost
- efficiency
- construction/installation lead times
- environment compliance;
- environment considerations; and
- costs of generation.

[29] Burr (1998)

The choice of fuel is influenced first of all by the local resource base. For example, the existing generation capacity in all of Latin America, New Zealand, and Canada are predominantly hydropower. Power plants in the U.S., Australia, and China are using mainly coal. Indigenous and imported coal, however, is also a least cost option in Indonesia, Malaysia, the Philippines, and Thailand. Coal-fired private power projects are being developed in these countries. Natural gas is the main fuel for power generation in Brunei, Indonesia, Malaysia, Thailand, and Vietnam. And because natural gas is also available in significant quantities in Australia, Canada, China, Latin America, New Zealand, and the US, IPPs in these countries are also using natural gas. Thus, for example, capacity additions under implementation and planned in Latin America will tap the rich gas resource of the entire region through indigenous development and cross-border cooperation. In Peru and Mexico, domestic gas fields are being developed to supply to IPP projects. IPPs in Chile will be supplied by natural gas from neighboring Argentina. Several IPP projects in New Zealand that are under consideration will use geothermal and natural gas. More than half of the non-utility generation in the U.S. comes from natural gas-fired power plants and majority of the planned additions will also use natural gas. Few gas projects are also being developed in China and Australia. Russia has a good balance of coal and natural gas in its generation mix.

Relative fuel prices are also a major factor in the fuel choice of IPPs as well as utilities undergoing privatization and restructuring. Both are concerned about increasing competitiveness and therefore, minimizing costs. In general, coal remains a very attractive option because of its stable and declining prices in real terms. However, non-price factors are driving the increasing preference for natural gas.

Gas-fired power plants are often the particularly attractive option for IPPs because of:[30]

- their relatively low capital construction cost;
- the use of a well-established technology;
- their shorter construction lead times;
- their relatively high fuel conversion efficiency; and
- their lower environmental impacts.

Privatization and deregulation of energy markets worldwide are compelling utilities and independent power producers to be more competitive. In this type of environment, there is a strong preference for equipment that has high conversion efficiency and that can be installed in months rather than in years. Gas turbine technologies feature both.

Complying with national and international environmental regulations is also one major factor influencing the choice of fuel and technology. Governments are putting in place more stringent environmental emission standards and regulations as a result of increasing environmental awareness and partly in response to pressures from the international community. Private power developers seeking additional financing have also to comply with environmental requirements of multilateral and bilateral financial institutions and international commercial banks, which are increasingly developing their own environmental compliance process.

Gas-fired generation technologies have become attractive also because of the less environmental emissions associated with natural gas burning than coal and oil, and therefore facilitates compliance to national and international environmental regulations.

However, improvements in coal-firing technology, along with the successful commercialization of fluidized bed combustion, have resulted in clean and efficient coal-fired power plants. Clean coal technologies are the most attractive option where low-cost coal is available (e.g. China, Australia, and Indonesia), or when the supply of gas is limited (Philippines and Thailand).

[30] Apogee Research (1997)

The immediate factor driving the choice of fuel for power plant is the cost of generation. This is a function not only of the cost of fuel and technology, but also of the economic and technical assumptions used in calculating generation costs. Gas-fired technologies, in most cases, are the least cost option. In particular:[31]

- gas-fired power plants increase their competitiveness when using high discount rates;
- the levelized generation cost of gas-fired power plants is not very sensitive to load factor variation; and
- for gas-fired power plants, capital costs represent only a small part of total levelized costs and, therefore, increasing the economic lifetime has little influence on levelized generation costs.

Choosing gas-fired generation technologies, however, is very sensitive to natural gas prices assumption as fuel accounts for more than 60% of total gas generation costs. Clean coal technologies become an attractive option at higher levels of natural gas prices.

Source: CEERD, *Coal and Natural Gas Competition in APEC Economies*, CEERD/APEC Clean Fossil Energy Experts Group, August 1999.

[31] IEA (1998).

Appendix 2: Risks and Benefits of Different Types of PPAs

	Main features	Risks	Benefits
Must-run or take-or-pay (e.g. Philippines, Belize, Colombia)	guarantees the sale of a stipulated amount of power and energy in the life of a contract	has three separate effects on the performance of the sector: – no competitive pressure for the IPP to lower costs, so that efficient operation depends solely on the profit motive; – dispatch can occur out of the merit order, leading to a loss of a system's productive efficiency; – the lack of competition for market share between the IPP and other generators means that, even if operated efficiently, the IPP poses no threat to other generators purchaser must pay for any contracted output that it does not take from IPP no issue of economic dispatch for the plant even when other plants have lower costs	most attractive for IPPs
Economic dispatch (e.g Jamaica, Dominican Republic)	capacity price is again related to availability, and the energy price is paid only for the energy dispatched according to costs	IPPs are not guaranteed energy sales requires an entity to determine dispatch on cost related basis energy prices linked to a cost index do not allow cost savings to be passed on to consumers or reflected in the prices that influence dispatch decisions (that is, the contractual energy costs) dispatch might not occur according to a true merit order, and systemwide generation costs could be unnecessarily high provides no competitive incentives for the supply of	plants are dispatched according to economic ranking

		energy	
Generator trading (e.g. Chile)	generators trade in a market based on economic dispatch: – contract prices for energy are predetermined for all generators, but generators bid for availability for the next period – the dispatch agency or power purchaser determines the least- cost dispatch on the basis of the contract prices and announces the schedule – generators can then trade energy among themselves	benefits are not passed on to consumers, because generator prices are tied to the cost index complicated to operate because the power purchaser must determine dispatch in advance and keep records of transactions between companies, and generators need to have sophisticated systems	lowers total costs of generation can lead to competitive pressure for generators to improve efficiency once actual costs start to diverge from the index
Competitive pool (e.g. England and Wales, Argentina, New South Wales, Norway)	prices for energy are bid rather than related to costs by formula: – generators bid their capacity availability and their offered energy price – pool operator then determines economic dispatch and pays for energy on the basis of marginal bid prices and for capacity on the basis of declared availability and a formula that gives signals for long-term investment	problems in setting up and running a pool probably feasible only for a sizeable market with several generators and competitive management	lower prices when there is real competition

Source: Robert Bacon, "Competitive contracting for privately generated power," *Public Policy for the Private Sector*, Note No. 47, World Bank, May 1995.